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The Interface between Automation and the Substation¹

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6.1 Introduction

An electric utility substation automation (SA) system depends on the interface between the substation and its associated equipment to provide and maintain the high level of confidence demanded for power system operation. It must also serve the needs of other corporate users to a level that justifies its existence. This chapter describes typical functions provided in utility SA systems and some important considerations in the interface between substation equipment and the automation system components.

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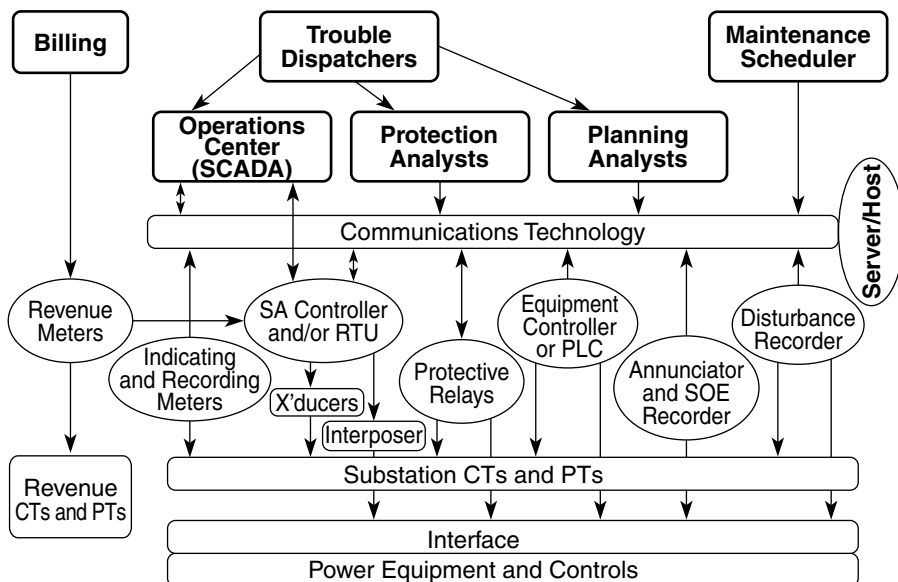


FIGURE 6.1 Power-station SA system functional diagram.

6.2 Physical Considerations

6.2.1 Components of a Substation Automation System

The electric utility SA system uses a variety of devices integrated into a functional package by a communications technology for the purpose of monitoring and controlling the substation. SA systems incorporate microprocessor-based intelligent electronic devices (IEDs), which provide inputs and outputs to the system. Common IEDs are protective relays, load survey and operator indicating meters, revenue meters, programmable logic controllers (PLC), and power equipment controllers of various descriptions. Other devices may also be present, dedicated to specific functions within the SA system. These may include transducers, position monitors, and clusters of interposing relays. Dedicated devices may use a controller (SA controller) or interface equipment such as a conventional remote terminal unit as a means of integration into the SA system. The SA system typically has one or more communications connections to the outside world. Common communications connections include utility operations centers, maintenance offices, and engineering centers. Most SA systems connect to a traditional SCADA (supervisory control and data acquisition) system master station serving the real-time needs for operating the utility network from an operations center. SA systems may also incorporate a variation of the SCADA remote terminal unit (RTU) for this purpose, or the RTU function may appear in an SA controller or host computer. Communications for other utility users is usually through a bridge, gateway, or network processor. The components described here are illustrated in Figure 6.1.

6.2.2 Locating the Interface Equipment

The SA system interfaces to control station equipment through interposing relays and to measuring circuits through meters, protective relays, transducers, and other measuring devices as indicated in Figure 6.1. These interfaces may be associated with, and integral to, an IED, or they may be dedicated interface devices for a specific automation purpose. The interfaces may be distributed throughout the station or centralized within one or two cabinets. Available panel space, layout of station control centers, as well as engineering and economic judgment are major factors in selecting a design.

The centralized interface simplifies installing an SA system in an existing substation, since the placement of the interface equipment affects only one or two panels (the new SA controller and interface equipment panels). However, the cabling from each controlled and monitored equipment panel must meet station panel wiring standards for insulation, separations, conductor sizing, and interconnection termination. Centralizing the SA system/station equipment interface has the potential to adversely affect the security of the station, as many control and instrument transformer circuits become concentrated in a single panel or cabinet and can be seriously compromised by fire and invite human error. This practice has been widely used for installing earlier SCADA systems, where all the interfaces centered around the SCADA remote terminal unit.

Placing the interface equipment on each monitored or controlled panel is much less compromising, but may be more costly and difficult to design. Each interface placement must be individually located, and more panels are affected. If a low-energy interface (less than 50 V) is used, a substantial savings in cable cost may be realized, since interconnections between the SA controller and the interface devices can be made with less expensive cable and hardware. Low-energy interconnections also lessen the impact on the cabling system of the substation, reducing the need for additional cable trays, wireways, and ducts.

The distributed approach is more logical when the SA system incorporates protective-relay IEDs, panel-mounted indicating meters, or control-function PLCs. Protection engineers usually insist on separating protection devices into logical groups based on substation configuration for security. Similar concerns often dictate the placement of indicating meters and PLCs. Many utilities have abandoned the operator “bench board” in substations, thereby distributing the operator control and indication hardware throughout the substation. The interface to the SA system becomes that of the IED on the substation side and a communications channel on the SA side. Depending on the communications capability of the IEDs, the SA interface can be as simple as a shielded, twisted-pair cable routed between IEDs and the SA controllers. The communications interface can also be complex where short-haul RS-232 connections to a communications controller are required. These pathways can also utilize optical-fiber systems and unshielded twisted-pair (UTP) ethernet cabling or even coaxial cable or some combination thereof.

As the cabling distances within the substation increase, system installation costs increase, particularly if additional cable trays, conduit, or ducts are required. Using SA communication technology and IEDs can reduce interconnection costs. Distributing multiple small SA hubs throughout the substation can reduce cabling to that needed for a communications link to the SA controller. Likewise, these hubs can be isolated using fiber-optic technology for improved security and reliability.

6.2.3 Environment

The environment of a substation is challenging for SA equipment. Substation control buildings are seldom heated or air-conditioned. Ambient temperatures can range from well below freezing to above 100°F (40°C). Metal-clad switchgear substations can reach ambient temperatures in excess of 140°F (50°C). Temperature changes stress the stability of measuring components in IEDs, RTUs, and transducers. Good temperature stability is important in SA system equipment and must be defined in the equipment purchase specifications. Designers of SA systems for substations need to pay careful attention to the temperature specifications of the equipment selected for SA. In many environments, self-contained heating or air conditioning may be advisable.

When equipment is installed in outdoor enclosures, the temperature cycling problem is aggravated, and moisture from precipitation leakage and from condensation becomes troublesome. Outdoor enclosures usually need heaters to control the temperature and prevent condensation. The placement of heaters should be reviewed carefully when designing an enclosure, as they can aggravate temperature stability and even create hot spots within the cabinet that can damage components and shorten life span. Heaters near the power batteries help improve low-temperature performance but adversely effects life span at high ambient temperatures. Obviously, keeping incident precipitation out of the enclosure is very important. Drip shields and gutters around the door seals will reduce moisture penetration. Venting the cabinet helps limit the possible

buildup of explosive gases from battery charging but may pose a problem with the admittance of moisture. Solar-radiation shields may also be required to keep enclosure temperature manageable. Specifications that identify the need for wide temperature-range components, coated circuit boards, and corrosion-resistant hardware are part of specifying and selecting SA equipment for outdoor installation.

Environmental factors also include airborne contamination from dust, dirt, and corrosive atmospheres found at some sites. Special noncorrosive cabinets and air filters may be required for protection against the elements. It is also necessary to keep insects and wildlife out of equipment cabinets. In some regions seismic requirements are important enough to receive special consideration.

6.2.4 Electrical Environment

The electrical environment of a substation is severe. High levels of electrical noise and transients are generated by the operation of power equipment and their controls. Operation of high-voltage disconnect switches can generate transients that appear throughout the station on current, potential, and control wiring entering or leaving the switchyard. Station controls for circuit breakers, capacitors, and tap changers can also generate transients found throughout the station on battery-power and station-service wiring. EHV stations also have high electrostatic field intensities that couple to station wiring. Finally, ground rise during faults or switching can damage electronic equipment in stations.

Effective grounding is critical to controlling the effects of substation electrical noise on electronic devices. IEDs need a solid ground system to make their internal suppression effective. Ground systems should be radial, with signal and protective grounds separated. They require large conductors for “surge” grounds, making ground leads as short as possible, and establishing a single ground point for logical groupings of equipment. These measures help to suppress the introduction of noise and transients into measuring circuits. A discussion of this topic is usually found in the IED manufacturer’s instruction book, and their advice should be heeded.

The effects of electrical noise can be controlled with surge suppression, shielded and twisted-pair cabling, as well as careful cable separation practices. However, suppressing surges with capacitors, metal oxide varistors (MOV), and semiconducting overvoltage “transorbs” on substation instrument transformer and control wiring can protect IEDs. They can create reliability problems as well. Surge suppressors must have sufficient energy-absorbing capacity and be coordinated so that all suppressors clamp around the same voltage. Otherwise, the lowest-dissipation, lowest-voltage suppressor will become sacrificial. Multiple failures of transient suppressors can short-circuit important station signals to ground, leading to blown potential fuses, shorted current transformers (CT), shorted control wiring, and even false tripping.

While every installation has a unique noise environment, some testing can help prevent noise problems from becoming unmanageable. IEEE Surge Withstand Capability Test C37.90-1992 addresses the transients generated by the operation of high-voltage disconnect switches and electromechanical control devices. This test can be applied to devices in a laboratory or on the factory floor, and it should be included when specifying station interface equipment. Insulation resistance and high-potential tests are also sometimes useful and are standard requirements for substation devices for many utilities.

6.3 Analog Data Acquisition

6.3.1 Measurements

Electric utility SA systems gather power system performance parameters (i.e., volts, amperes, watts, and Vars) for system generators, transmission lines, transformer banks, station buses, and distribution feeders. Energy output and usage quantities (i.e., kilowatt-hours and kiloVar-hours) are also important for the exchange of financial transactions. Other quantities such as transformer temperatures, insulating gas pressures, fuel tank levels for on-site generation, or head level for hydro generation might also be measured and transmitted as analog values. Often, transformer tap positions, regulator positions, or

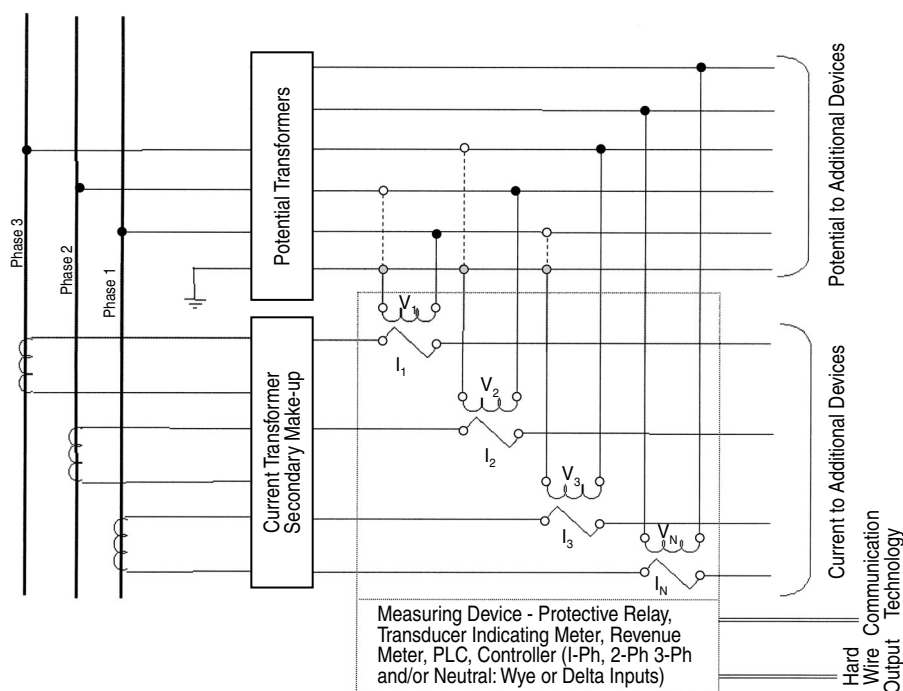


FIGURE 6.2 SA system measuring interface.

other multiple position quantities are also transmitted as if they were analog values. These values enter the SA system through IEDs, transducers, and sensors.

Transducers and IEDs measure electrical quantities (watts, VARs, volts, amps) with instrument transformers provided in power equipment, as shown in Figure 6.2. They convert instrument transformer outputs to digital values or dc voltages or currents that can be readily accepted by a traditional SCADA RTU or SA controller.

Analog values can also be collected by the SA system from substation meters, protective relays, revenue meters, and recloser controls as IEDs. Functionally the process is equivalent, but the IEDs perform signal processing and digital conversion directly as part of their primary function. IEDs use a communications channel for passing data to the SA controller instead of conventional analog signals.

6.3.2 Performance Requirements

In the initial planning stages of an SA system, the economic value of the data to be acquired needs to be weighed against the cost to measure it. A balance must be struck to achieve the data quality required to suit the users and functions of the system. This affects the conceptual design of the measuring interface and provides input to the performance specifications for IEDs and transducers as well as the measuring practices applied. This step is important. Specifying a higher performance measuring system than required raises the overall system cost. Conversely, constructing a low-performance system adds costs when the measuring system must be upgraded. The tendency to select specific IEDs for the measuring system without assessing the actual measuring technology can lead to disappointing performance.

The electrical relationship between measurements and the placement of available instrument transformer sources deserves careful attention to insure satisfactory performance. Many design compromises must be made when installing SA monitoring in an existing power station because of the limited availability of measuring sources. This is especially true when using protective relays as load-monitoring data sources (IEDs). Protection engineers often ignore current omissions or contributions at a measuring

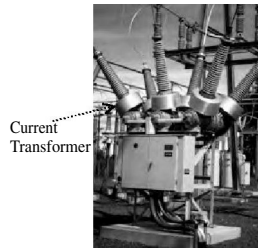


FIGURE 6.3 Bushing current transformer installation.

point, as they may not affect the performance of protection during faults. These variances are often intolerable for power flow measurements. The placement of a measuring source can also result in measurements that include or exclude reactive contributions of a series or shunt reactor or capacitor; measurements that include reactive component contributions of a transformer bank; or measurements that are affected when a section breaker is open because the potential source is on an adjacent bus. Power system charging current and unbalances also influence measurement accuracy, especially at low load levels. The compromises are endless, and each produces an unusual operating condition in some state. When deficiencies are recognized, the changes to correct them can be very costly, especially if instrument transformers must be installed, moved, or replaced to correct the problem.

The overall accuracy of measured quantities is affected by a number of factors. These include instrument transformer errors, IED or transducer performance, and analog to digital (A/D) conversion. Accuracy is not predictable based solely on the IED, transducer, or A/D converter specifications. Significant measuring errors often result from instrument transformer performance and errors induced in scaling.

Revenue metering accuracy is usually required for monitoring power system interconnections and feeding economic-area-interchange dispatch systems. High accuracy, revenue-metering-grade instrument transformers and 0.25%-accuracy-class IEDs or transducers can produce consistent real power measurements with accuracy of 1% or better at 0.5 to 1.0 power factor, and reactive power measurements with accuracy of 1% or better at 0 to 0.5 power factors.

When an SA system provides information for internal telemetering of power flow, revenue-grade instrument transformers are not usually available. SA IEDs and transducers must often share less accurate instrument transformers provided for protective relaying or load monitoring. Overall accuracy under these conditions can easily decrease to 2 to 3% for real power, voltage, and current measurements and 5% or greater for reactive power.

6.3.3 Instrument Transformers

6.3.3.1 Current Transformers

Current transformers (CTs) of all sizes and types find their way into substations to provide the current replicas for metering, controls, and protective relaying. Some will perform well for SA applications, and some may be marginal. CT performance is characterized by ratio correction factor (turns ratio error), saturation voltage, phase-angle error, and rated burden. Bushing CTs installed in power equipment, as shown in Figure 6.3, are the most common type found in medium- and high-voltage power equipment. They are toroidal, having a single primary turn (the power conductor) that passes through their center. The current transformation ratio results from the number of turns wound on the core to make up the secondary. More than one ratio is often provided by tapping the secondary winding at multiple turn ratios. The core cross-sectional area, diameter, and magnetic properties determine the CT's performance. As the CT is operated over its current ranges, its deviations from specified turns ratio is characterized by its ratio-correction curve, sometimes provided by the manufacturer. At low currents, the exciting current causes ratio errors that are predominant until sufficient primary flux overcomes the effects of core magnetizing. Thus, watt or VAR measurements made at very low load may be substantially in error

both from ratio error and phase shift. Exciting-current errors are a function of individual CT construction. They are generally higher for protection CTs than metering CTs by design.

Metering CTs are designed with core cross sections chosen to minimize exciting-current effects and are allowed to saturate at fault currents. Larger cores are provided for protection CTs where high-current saturation must be avoided for the CT to faithfully reproduce high currents for fault sensing. The exciting current of the larger core at low load is not considered important for protection. Core size and magnetic properties limit the ability of CTs to develop voltage to drive secondary current through the circuit load impedance (burden). This is an important consideration when adding SA IEDs or transducers to existing metering CT circuits, as added burden can affect accuracy. The added burden of SA devices is less likely to create metering problems with protection CTs at load levels, but it could have undesirable effects on protective relaying at fault levels. In either case, CT burdens are an important consideration in the design. Experience with both protection and metering CTs wound on modern high-silicon steel cores has shown, however, that both perform comparably once the operating current sufficiently exceeds the exciting current if secondary burden is kept low.

Occasions arise where it is necessary to obtain current from more than one source by summing currents with auxiliary CTs. This will perform satisfactorily only if the auxiliaries used are adequate. If the core size is too small to drive the added circuit burden, the auxiliaries will introduce excessive ratio and phase-angle errors that will degrade measurement accuracy. The use of auxiliary transformers must be approached with caution.

6.3.3.2 Potential Sources

The most common potential sources for power system measurements are either wound transformers (potential transformers) or capacitive divider devices (capacitor voltage transformers or bushing potential devices). Some new applications of resistor dividers and magneto-optic technologies are also becoming available. All provide scaled replicas of their high-voltage potential. They are characterized by their ratio, load capability, and phase-angle response. Wound potential transformers (PTs) provide the best performance with ratio and phase-angle errors suitable for revenue measurements. Even protection-type potential transformers can provide revenue-metering performance if the burden is carefully controlled. PTs are usually capable of supplying large potential circuit loads without degradation, provided their secondary wiring is of adequate size. For substation automation purposes, PTs are unaffected by changes in load or temperature. They are the preferred source for measuring potential.

Capacitor voltage transformers (CVTs) use a series stack of capacitors, connected as a divider to ground, along with a low-voltage transformer to obtain a secondary voltage replica. They are less expensive than wound transformers and can approximate wound transformer performance under controlled conditions. While revenue-grade CVTs are available, CVTs are less stable and less accurate than wound PTs. Older CVTs may be totally unsatisfactory. Secondary load and ambient temperature can affect CVTs. CVTs must be individually calibrated in the field to bring their ratio errors within 1%, and must be recalibrated whenever the load is changed. Older CVTs can change ratio up to $\pm 5\%$ with ambient temperature variation. In all, CVTs are a reluctant choice for measuring SA systems. When CVTs are the only choice, consideration should be given to using the more modern devices for better performance along with a periodic calibration program to maintain their performance at satisfactory levels.

Bushing capacitor potential devices (BCPD) use a tap made in the capacitive grading of a high-voltage bushing to provide the potential replica. They can supply only very limited secondary load and are very load sensitive. They can also be very temperature sensitive. As with CVTs, if BCPDs are the only choice, they should be individually calibrated and periodically checked.

6.3.4 Transducers

Transducers measure power system parameters by sampling instrument transformer secondaries. They provide a scaled, low-energy signal that represents a power system quantity that the SA interface controller can easily accept. Transducers also isolate and buffer the SA interface controller from the power system

and substation environments. Transducer outputs are dc voltages or currents in the range of a few tens of volts or milliamperes.

Transducers measuring power system electrical quantities are designed to be compatible with instrument transformer outputs. Potential inputs are based around 120 or 115 Vac, and current inputs accept 0 to 5 A. Many transducers can operate at levels above their normal ranges with little degradation in accuracy provided their output limits are not exceeded. Transducer input circuits share the same instrument transformers as the station metering and protection systems; thus, they must conform to the same wiring standards as any switchboard component. Wiring standards for current and potential circuits vary between utilities, but generally 600-V-class wiring is required, and no. 12 AWG or larger wire is used. Special termination standards also apply in many utilities. Test switches for “in-service” testing of transducers are often provided to make it possible to test transducers without shutting down the monitored equipment. Transducers may also require an external power source to operate. When this is the case, the reliability of this source is crucial in maintaining data flow.

Transducer outputs are voltage or current sources specified to supply a rated voltage or current into a specific load. For example, full output may correspond to 10 V at up to 1.0 mA or 1.0 mA into 10 k Ω , up to 10 V maximum. Some over-range capability is provided in transducers so long as the maximum current or voltage capability is not exceeded. The over-range can vary from 20 to 100%, depending on the transducer. However, accuracy is usually not specified for the over-range area.

Transducer outputs are usually wired with shielded, twisted-pair cable to minimize stray signal pickup. In practice, no. 18 AWG conductors or smaller are satisfactory, but individual utility practices differ. It is common to allow transducer output circuits to remain isolated from ground to reduce the susceptibility to transient damage, although some SA controller suppliers provide a common ground for all analogs, often to accommodate electronic multiplexers. Some transducers may also have a ground reference associated with their outputs. Double grounds, where transducer and controller both have ground references, can cause major reliability problems. Practices also differ somewhat on shield grounding, with some shields grounded at both ends, but it is also common practice to ground shields at the SA controller end only. When these signals must cross a switchyard, however, it is a good practice to not only provide the shielded twisted pairs, but it also to provide a heavy-gauge overall cable shield. This shield should be grounded where it leaves a station control house to enter a switchyard and where it reenters another control house. These grounds are terminated to the station ground mass, and not to the SA analog grounds bus.

6.3.5 Scaling of Analog Values

In an SA system, the transition of power system measurements to database values or displays is a process that entails several steps of scaling, each with its own dynamic range. Power system parameters are first scaled by current and potential transformers, then by IEDs or transducers. In the process, an analog-to-digital conversion occurs as well. Each of these steps has its own proportionality constant that, when combined, relates the digital coding of the data value to the primary quantities. At the data receiver or master station, these are operated on by one or more constants to convert the data to user-acceptable values for databases and displays.

SA system measuring performance can be severely affected by data value scaling. Optimally, under normal power system conditions, each IED or transducer should be operating in its most linear range and utilize as much A/D conversion range as possible. Scaling should take into account the minimum, normal, and maximum values for the quantity, even under abnormal or emergency loading conditions. Optimum scaling balances the expected value at maximum, the current and potential transformer ratios, the IED or transducer range, and the A/D range to utilize as much of the IED or transducer output and A/D range as possible under normal power system conditions without driving the conversion over its full scale at maximum value. This practice minimizes the quantizing error of the A/D conversion process and provides the best quantity resolution.

Conversely, scaling some IEDs locally makes their data difficult to use in an SA system. A solution to this problem is to set the IED scaling to unity and apply all the scale factors at the data receivers. Under the practical restraints imposed when applying SA to an existing substation, scaling can be expected to be compromised by available instrument transformer ratios and A/D or IED scaling provisions. A reasonable selection of scale factor and range would provide half output or more under normal conditions but not exceed 90% of full range under maximum load.

6.3.6 Intelligent Electronic Devices (IED) as Analog Data Sources

Technological advancements have made it practical to use electronic substation meters, protective relays, and even reclosers and regulators as sources of analog data. IED measurements are converted directly to digital form and passed to the SA system via a communications channel while the IED performs its primary function. In order to use IEDs effectively, it is necessary to assure that the performance characteristics of the IED fit the requirements of the system. Some IEDs designed for protection functions, where they must accurately measure fault currents, do not measure low load accurately. Others, where measuring is part of a control function, may lack overload capability or have insufficient resolution. Sampling rates and averaging techniques will affect the quality of data and should be evaluated as part of the system product selection process. With reclosers and regulators, the measuring CTs and PT are often contained within the equipment. They may not be accurate enough to meet the measuring standards set for the SA system. Regulators may only have a single-phase CT and PT. These issues challenge the SA system integrator to deliver a quality system.

The IED communications channel becomes an important data highway and needs attention to security, reliability, and most of all, throughput. A communications interface is needed in the SA system to retrieve and convert the data to meet the requirement of the master or data receiver.

6.3.7 Integrated Analog Quantities — Pulse Accumulators (PA)

Some power system quantities of interest are energy-transfer values derived from integrating instantaneous values over an arbitrary time period, usually 15-min values for one hour. The most common of these is watt-hours, although VAR-hours and amp-squared-hours are not uncommon. They are usually associated with energy interchange over interconnecting tie lines, generator output, at the boundary between a transmission provider and distribution utility, or the load of major customers. In most instances, they originate from a revenue-metering package that includes revenue-grade instrument transformers and one or more watt-hour and VAR-hour meters. Most utilities provide remote and/or automatic reading with a local recording device such as a magnetic tape recorder or remote meter-reading device. They also can be interfaced to an SA system.

Integrated energy-transfer values are traditionally recorded by counting the revolutions of the disc on an electromechanical watt-hour meter-type device. Newer technology makes this concept obsolete, but the integrated interchange value continues as a mainstay of energy interchange between utilities and customers. In the old technology, a set of contacts opens and closes in direct relation to the disc rotation, either mechanically from a cam driven by the meter disc shaft, or through the use of opto-electronics and a light beam interrupted by or reflected off the disc. These contacts can be standard form “A,” form “B,” form “C,” or a form “K,” which is peculiar to watt-hour meters. Modern revenue meters often mimic this feature, as do some analog transducers. Each contact transfer (“pulse”) represents an increment of energy transfer as measured by a watt-hour meter. Pulses are accumulated over a period of time in a register, and then the total is recorded on command from a clock.

When applied to SA systems, energy-transfer quantities are processed by metering IEDs, PAs in an RTU, or an SA controller. The PA receives contact closures from the metering package and accumulates them in a register. On command from the master station, the pulse count is frozen, then transmitted. The register is sometimes reset to zero to begin the cycle for the next period. This command is synchronized to the master station clock, and all “frozen” accumulator quantities are polled some time later when

time permits. Some RTUs can freeze and store their pulse accumulators from an internal or local external clock should the master “freeze-and-read” command be absent. These can be internally “time tagged” for transmission when commanded by the master station. High-end meter IEDs retain interval accumulator reads in memory that can be retrieved by the utility’s automatic meter-reading system. They can share multiple ports and supply data to the SA system. Other options include the capability to arithmetically process several demand quantities to derive a resultant. Software to “de-bounce” the demand contacts is also sometimes available.

Integrated energy-transfer telemetering is almost always provided on tie lines between bordering utilities and at the transmission-distribution or generation-transmission boundaries. The location of the measuring point is usually specified in the interconnection agreement contract, along with a procedure to insure metering accuracy. Some utilities agree to share a common metering point at one end of a tie and electronically transfer the interchange reading to the bordering utility. Others insist on having their own duplicate metering, sometimes specified to be a backup service. When a tie is metered at both ends, it is important to verify that the metering installations are in agreement. Even with high-accuracy metering, however, some disagreement can be expected, and this is often a source of friction between utilities.

6.4 Status Monitoring

Status indications are an important function of SA systems for the electrical utility. Status monitoring is provided for power circuit breakers, circuit switchers, reclosers, motor-operated disconnect switches, and a variety of other on-off functions in a substation. Multiple on-off states are sometimes used to describe stepping or sequential devices. In some cases, status points might be used to convey a digital value such as a register, where each point is one bit of the register.

Status points can be provided with status-change memory so that changes occurring between data reports can be monitored. Status changes may also be “time tagged” to provide sequence of events. Status indications originate from auxiliary switch contacts that are mechanically actuated by the monitored device. Interposing relay contacts are also used for status points, where the interposer is driven from auxiliary switches. This practice is common, depending on the utility and the availability of spare contacts. The exposure of status-point wiring to the switchyard environment is often a consideration in installing interposing relays.

6.4.1 Contact Performance

The mechanical response of either relay or auxiliary switch contacts can complicate status monitoring. Contacts may electrically open and close several times (mechanically “bounce”) before finally settling in the final position when they transfer from one position to another. The input point may interpret the bouncing of the status contact as multiple operations of the primary device. A “mercury wetted” contact is sometimes used to minimize contact bounce. Another technique used is to employ “C”-form contacts for status indications so that status changes are recognized only when one contact closes followed by the opening of its companion. Contact changes occurring on one contact only are ignored. C-contact arrangements are more immune to noise pulses. Another technique to deal with bouncing is to wait for a period of time before recognizing the change, giving the contact a chance to bounce into its final state before reporting the change.

Event recording with high-speed resolution is particularly sensitive to contact bounce, as each transition is recorded. When the primary device is subject to pumping or bouncing induced from mechanical characteristics, it may be difficult to prevent excessive status-change reporting. When interposing devices are used, event contacts can also contain unwanted delays that can confuse interpretation of event sequences. While this may not be avoidable, it is important to know the response time of all event devices so that event sequences can be correctly interpreted.

IEDs often have “de-bounce” algorithms in their programming to filter contact bouncing. These algorithms allow the user to tune the de-bouncing to be tolerant of bouncing contacts.

6.4.2 Wetting Sources

Status points are usually isolated “dry” contacts, and the monitoring power (wetting) is supplied from the input point. Voltage signals from a station control circuit can also be monitored by SA controllers and interpreted as status signals. Equipment suppliers can provide a variety of status-point input options. When selecting between options, the choice balances circuit isolation against design convenience. The availability of spare isolated contacts often becomes an issue in choice. Voltage signals may eliminate the need for spare contacts, but these signals can require circuits from various parts of the station and from different control circuits to be brought to a common termination location. This compromises circuit isolation within the station and raises the possibility of test personnel causing circuit misoperation. Usually, switchboard wiring standards would be required for this type of installation, which could increase costs. Voltage inputs are often fused with small fuses at the source to minimize the risk that the exposed wiring will compromise the control circuits.

In installations using isolated “dry” contacts, the wetting voltage is sourced from the station battery, an SA controller, or IED supply. Each monitored control circuit must then provide an isolated contact for status monitoring. Circuit isolation occurs at each control panel, thus improving the overall security of the installation. It is common for many status points to share a common supply, either station battery or a low voltage supply provided for this purpose. When status points are powered from the station battery, the monitored contacts have full control potential appearing across their surfaces and thus can be expected to be more immune to open-circuit failures from contact-surface contamination. Switchboard wiring standards would be required for this type of installation. An alternative source for status points is a low-voltage wetting supply. Wiring for low-voltage-sourced status points may not need to be switchboard standard in this application, which could yield some economies. Usually, shielded, twisted pairs are used with low-voltage status points to minimize noise effects. Concern over contact reliability due to the lower “wetting” voltage can be partially overcome by using contacts that are closed when the device is in its normal position, thereby maintaining a loop current through the contact. For improved reliability, some SA systems provide a means to detect wetting-supply failure. Where multiple IEDs are status-point sources, it can be difficult to detect a lost wetting supply.

In either approach, the status-point loop current is determined by the monitoring-device design. Generally, the loop current is 1.0 to 20 mA. Filter networks and/or software filtering is usually provided to reduce noise effects and false changes resulting from bouncing contacts.

6.4.3 Wiring Practices

When wiring status points, it is important to make cable runs radially between the monitor and the monitored device. Circuits where status circuit loops are not parallel pairs are subject to induced currents that can cause false status changes. Circular loops most often occur when using spare existing conductors in multiple cables or when using a common return connection for several status points. Designers should be wary of this practice. The resistance of status loops can also be an important consideration. Shielded, twisted pairs make the best interconnection for status points, but this type of cable is not always readily available in switchboard standard sizes and insulation for use in control battery-powered status circuits.

Finally, it is important to provide for testing status circuits. Test switches or jumper locations for simulating open or closed status circuits are needed as well as a means for isolating the circuit for testing.

6.5 Control Functions

The supervisory control functions of electric utility SA systems provide routine and emergency switching and operating capability for station equipment. SA controls are most often provided for circuit breakers, reclosers, and switchers. It is not uncommon to also include control for voltage regulators, tap-changing transformers, motor-operated disconnects, valves, or even peaking units through an SA system.

A variety of different control outputs are available from IEDs and SA controllers, which can provide both momentary timed control outputs and latching-type interposing. Latching is commonly associated

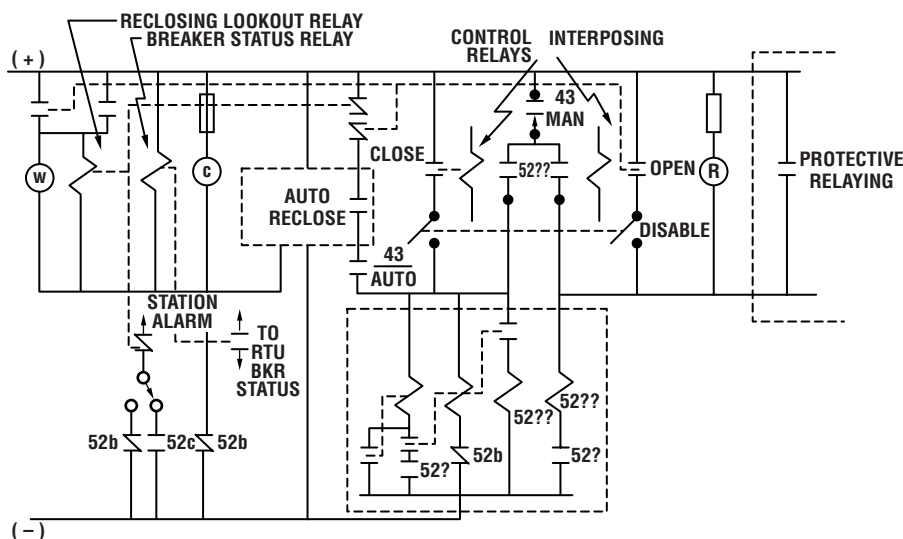


FIGURE 6.4 Schematic diagram of a breaker control interface.

with blocking of automatic breaker reclosing or voltage controllers for capacitor switching. A typical interface application for controlling a circuit breaker is shown in Figure 6.4.

6.5.1 Interposing Relays

Power station controls often require high power levels and operate in circuits powered from 48-, 125-, or 250-Vdc station batteries or from 120- or 240-Vac station service. Control circuits often must switch 10 or 20 A to effect their action, which imposes constraints on the interposing devices. The interposing between an SA controller or IED and station controls commonly requires the use of large electromechanical relays. Their coils are driven by the SA control system through static or pilot duty relay drivers, and their contacts switch the station control circuits. Interposing relays are often specified with 25-A, 240-Vac contact rating to insure adequate interrupting duty. However, where control circuits allow it, smaller interposing relays are also used, often with only 10- or 3-A contacts. When controlling dc circuits, the large relays may be required, not because of the current requirements, but to provide the long contact travel needed to interrupt the arc associated with interrupting an inductive dc circuit. Note that most relays that would be considered for the interposing function do not carry dc interrupting ratings. “Magnetic blowout” contacts, contacts fitted with small permanent magnets that lengthen the interruption arc to aid in extinguishing it, may also be used to improve interrupting duty. They are polarity sensitive, however, and work only if correctly wired. Correct current flow direction must be observed.

Many SA controllers and IEDs require the use of surge suppression to protect their control output contacts. A fast-switching diode can be used across the driven coil to commute the coil-collapse transient when the coil is de-energized. As the magnetic field of the device coil collapses on de-energization, the coil voltage polarity reverses, and the collapsing field generates a back EMF in an attempt to sustain the coil current. The diode conducts the back EMF and prevents the buildup of high voltage across the coil. The technique is very effective. It requires the diode to handle the steady-state current of the coil and be able to withstand at least three times the steady-state voltage. Failure of the diode in the shorted mode will disable the device and cause a short circuit of the control driver, although some utilities use a series resistor with the diode to reduce this reliability problem.

Other transient suppressors include “transorbs” and metal oxide varistors (MOV). Transorbs behave like back-to-back zener diodes and clamp the voltage across their terminals to a specified voltage. They are reasonably fast. MOVs are very similar, but the suppression takes place as the voltages across them

cause the metal oxide layers to break down, and they are not as fast. Both transorbs and MOVs have energy rating in joules. They must be selected to withstand the energy of the device coil. Many applications of transorbs and MOVs clamp the transients to ground rather than clamping them across the coil. In this configuration, the ground path must be low impedance in order for the suppression to be effective.

6.5.2 Control Circuit Designs

Many station control circuits can be designed so that the interrupting-duty problem for interposing relays is minimized, thereby allowing smaller interposing relays to be used. These circuits are designed so that once they are initiated, some other contact in the circuit interrupts control current in preference to the initiating device. These are easily driven from momentary outputs. The control logic is such that the initiating contact is bypassed once control action begins, and it remains bypassed until control action is completed. The initiating circuit current is then interrupted, or at least greatly reduced, by a device in another portion of the control circuit. This eliminates the need for the interposing relay to interrupt heavy control circuit current. This is typical of modern circuit breaker closing circuits, motor-operated disconnects, and many circuit switchers. Other controls that “self-complete” are breaker tripping circuits, where the tripping current is interrupted by the breaker auxiliary switch contacts long before the initiating contact opens.

Redesigning control circuits often simplifies the application of supervisory control. The need for large interposing relay contacts can be eliminated in many cases by simple modifications to the controlled circuit to make them “self completing.” An example of this would be the addition of any auxiliary control relay to a breaker control circuit, which maintains the closing circuit until the breaker has fully closed and provides antipumping should it trip free. This type of revision is often desirable, anyway, if a partially completed control action could result in some equipment malfunction.

Control circuits can also be revised to limit control-circuit response to prevent more than one action from taking place while under supervisory control. This includes preventing a circuit breaker from “pumping” if it were closed into a fault or failed to latch. Another example is to limit tap-changer travel to one tap per initiation.

6.5.3 Latching Devices

It is often necessary to modify control-circuit behavior when supervisory control is used to operate station equipment. Control mode changes that would ordinarily accompany manual local operation must also occur when action occurs through supervisory control. Many of these require latched interposing relaying, which modifies control behavior when supervisory control is exercised, and can be restored through supervisory or local control. The disabling of automatic circuit-breaker reclosing when a breaker is opened through supervisory control action is an example. Automatic reclosing must also be restored or reset when a breaker is closed through supervisory control. This concept also applies to automatic capacitor switcher controls that must be disabled when supervisory control is used and can be restored to automatic control through local or supervisory control.

These types of control modifications generally require a latching-type interposing design. Solenoid-operated control switches have become available that can directly replace a manual switch on a switchboard and can closely mimic manual control action. These can be controlled through supervisory control and can frequently provide the proper control behavior.

6.5.4 Intelligent Electronic Devices (IED) for Control

IEDs that have control capability accessible through their communications ports are available. Protective relays, panel meters, recloser controls, and regulators are common devices with control capability. They offer the opportunity to control substation equipment without a traditional interposing relay cluster for the interface, sometimes without even any control-circuit additions. Instead, the control interface is embedded in the IED. When using embedded control interfaces, the SA system designer needs to assess

the security and capability of the interface provided. These requirements should not change just because the interface devices are within an IED. External interposing may be required to meet circuit loads or interrupting duty.

When equipment with IEDs is controlled over a communications channel, the integrity of the channel and the security of the messaging system become important factors. Not all IEDs have select-before-operate capability common to RTUs and SCADA systems. Their protocols also may not have efficient error detection, which could lead to misoperation. In addition, the requirement to have supervisory control disabled for test and maintenance should not impact the IED's primary function.

6.6 Communications Networks inside the Substation

Substation automation systems are based on IEDs that share information and functionality by virtue of their communications capability. The communications interconnections can use hard copper, optical fiber, wireless, or a combination of these. The communications network is the glue that binds the system together. The communications pathways may vary in complexity, depending on the end goals of the system. Ultimately, the internal network passes information and functionality upward to the utility enterprise. Links to the enterprise can take a number of different forms and will not be discussed in this chapter.

6.6.1 Wire Line Networks

6.6.1.1 Point-to-Point Networks

The communications link from an IED to the SA system may be a simple point-to-point connection where the IED connects directly to an SA controller. Many IEDs can connect point to point to a multiported controller or data concentrator that serves as the SA system communications hub. In early integrations, these connections were simple RS-232 serial pathways similar to those between a computer and a modem. RS-232 does not support multiple devices on a pathway. Some IEDs will not communicate on a party line, since they do not support addressing. RS-232 is typically used for short distances, up to 50 ft. Most RS-232 connections are also solid device to device. Isolation requires special hardware. Often, utilities use point-to-point optical-fiber links to connect RS-232 ports together to insure isolation.

6.6.1.2 Point-to-Multipoint Networks

Most automation systems rely on point-to-multipoint connections for IEDs. IEDs that share a common protocol often support a "party line" communications pathway, where they share the channel. An SA controller can use this as a master-slave communications bus, where the SA controller controls the traffic on the channel. All devices on a common bus must be addressable so that only one device communicates at a time. The SA controller communicates with each device one at a time to prevent communications collisions.

RS-485 is the most common point-to-multipoint bus. It is a shielded twisted copper pair, terminated at each end of the bus with a termination resistor equal to the characteristic impedance of the bus cable. RS-485 buses support 32 devices on the channel. Maximum channel length is typically 4000 ft. The longer the bus, the more likely communications error will occur because of reflection on the transmission line; therefore, the longer the bus is, the slower it normally runs. RS-485 can run as fast as 1.0 Mbps, although most operate closer to 19.2 kbps or slower. The RS-485 bus must be linear, end to end. Stubs or taps will cause reflections. RS-485 devices are wired in a daisy-chain arrangement. RS-422 is similar to RS-485 except it is two pairs: one outbound and one inbound. This is in contrast to RS-485, where messages flow in both directions, as the channel is turned around when each device takes control of the bus while transmitting.

6.6.1.3 Peer-to-Peer Networks

There is a growing trend in IED communications to support peer-to-peer messaging. Here, each device has equal access to the communications bus and can message any other device. This is substantially

different than a master-slave environment, even where multiple masters are supported. A peer-to-peer network must provide a means to prevent message collisions, or to detect them and mitigate the collision.

PLC communications and some other control systems use a token passing scheme to give control to devices along the bus. This is often called “token ring.” A message is passed from device to device along the communications bus that gives the device authority to transmit messages. Different schemes control the amount of access time each “pass” allows. While the device has the token, it can transmit messages to any other device on the bus. These buses can be RS-485 or higher speed coaxial cable arrangements. When the token is lost or a device fails, the bus must restart. Therefore, token-ring schemes must have a mechanism to recapture order.

Another way to share a common bus as peers is to use a carrier sense multiple access with collision detection (CSMA/CD) scheme. Ethernet, IEEE Standard 802.x, is such a scheme. Ethernet is widely used in the information technology environment and is finding its way into substations. Ethernet can be coaxial cable or twisted-pair cabling. Unshielded twisted-pair (UTP) cable for high-speed ethernet, Category V (CAT V), is widely used for wire ethernet local area networks (LAN). Some utilities are extending their wide area networks (WAN) to substations, where it is becoming both an enterprise pathway and a pathway for SCADA and automation. Some utilities are using LANs within the substation to connect IEDs. A growing number of IEDs support ethernet communication over LANs. Where IEDs cannot support Ethernet, some suppliers offer network interface modules (NIM) to make the transition. A number of different communications protocols are appearing on substation LANs, embedded in a general purpose networking protocol such as TCP/IP.

While Ethernet can be a device-to-device network like RS-485, it is more common to wire devices to a hub or router. Each device has a “home run” connection to the hub. In the hub the outbound path of each device connects to the inbound path of all other devices. All devices hear a message from one device. Hubs can also acquire intelligence and perform a switching service. A switched hub passes outbound messages only to the intended recipient. That allows more messages to pass through without busying all devices with the task of figuring out for whom the message is intended. Routers connect segments of LANs and WANs together to get messages in the right place and to provide security and access control. Hubs and routers require operating power and therefore must be provided with a highly reliable power source in order to function during interruptions in the substation.

6.6.2 Optical Fiber Systems

Fiber optics is an excellent media for communications within the substation. It isolates devices electrically because it is nonconducting. This is very important because high levels of radiated electromagnetic fields and transient voltages are present in the substation environment.

Fiber optics can be used in place of copper cable runs to make point-to-point connections. A fiber media converter is required to make the transition from the electrical media to the fiber. They are available in many different configurations. The most common are Ethernet and RS-232 to fiber, but they are also available for RS-485 and RS-422. Fiber is ideal for connecting devices in different substation buildings or out in the switchyard. [Figure 6.5](#) illustrates a SCADA system distributed throughout a substation connected together with a fiber network.

6.6.2.1 Fiber Loops

Low-speed fiber communications pathways are often provided to link multiple substation IEDs on a common channel. The IEDs could be recloser controls, PLCs, or even protective relays distributed throughout the switchyard. While fiber is a point-to-point connection, fiber modems are available that provide a repeater function. Messages pass through the modem, in the RD port and out the TX port, to form a loop as illustrated in the [Figure 6.6](#). When an IED responds to a message, it breaks the loop and sends its message on toward the head of the loop. The fiber cabling is routed around to all devices to make up the loop. A break in the loop will make all IEDs inaccessible. Another approach to this architecture is to use bidirectional modems that have two paths around the loop. This technique is immune to single fiber breaks. It is also easy to service.

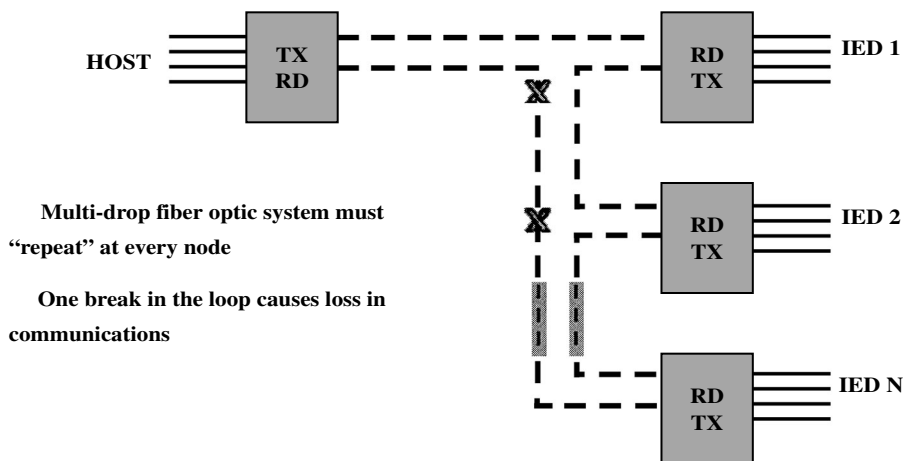


FIGURE 6.5 Fiber-optic loop.

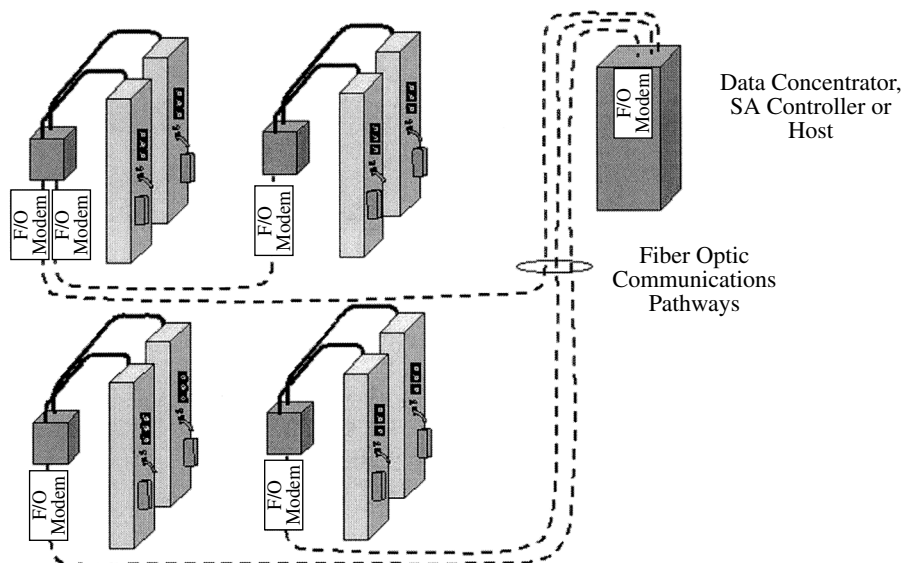


FIGURE 6.6 Fiber-optic network for distributed SCADA and automation.

Some utilities implement bidirectional loops to reach multiple small substations close to an access point to avoid building multiple access points. When the access point is a wire line that requires isolation, the savings can be substantial. Also, the devices may not be accessible except through a power-cable duct system, such as urban areas that are served by low-voltage networks. Here, the extra cost of the bidirectional fiber loop is often warranted.

6.6.2.2 Fiber Stars

Loop topology doesn't always fit substation applications. Some substation layouts better fit a star configuration, where all the fiber runs are “home runs” to a single point. To deal with star topologies, there are several alternatives. The simplest is to use multistrand fiber cables and make a loop with butt splices at the central point. While the cable runs can all be “home runs,” the actual configuration is a loop. However, there are star-configuration fiber modems available, which eliminates the need for creating loops. This modem supports multiple fiber-optic (F/O) ports and combines them to a single port.

Typically, the master port is an RS-232 connection, where outgoing messages on the RS-232 port are sent to all outgoing optical ports, and returning messages are funneled from the incoming optical ports to the receive side of the RS-232 port. Another solution is to make the modems at the central point all RS-485, where the messages can be distributed along the RS-485 bus.

6.6.2.3 Message Limitations

In the above discussion there are two limitations imposed by the media. First, there is no provision for message contention and collision detection. Therefore, the messaging protocol must be master-slave. Unsolicited reporting will not work because of the lack of collision detection. In fiber-loop topologies, outgoing messages will be injected into the loop at the head device and travel the full circumference of the loop and reappear as a received message to the sender. This can be confusing to some communications devices at the head end. That device must be able to ignore its own messages.

6.6.2.4 Ethernet over Fiber

As IEDs become network ready and substation SCADA installations take a more network-oriented topology, fiber-optic links for Ethernet will have increasing application in substations. Just as with slower speed fiber connections, Ethernet over fiber is great for isolating devices and regions in the substation. There are media converters and fiber-ready routers, hubs, and switches readily available for these applications. Because Ethernet has a collision detection system, the requirement to control messaging via a master-slave environment is unnecessary. The routers and switches take care of that problem. The star configuration is also easily supported with a multiport fiber router.

6.6.3 Communications between Facilities

Light-fiber (fiber-optic [F/O]) communications systems are readily available to owners of fiber right-of-way. Fiber-optic technology is very wideband and therefore capable of huge data throughputs, of which SCADA data might represent only a tiny fraction of the available capacity.

Utilities have taken different paths in dealing with F/O opportunities. Some have chosen to leverage the value of their existing right of way by building F/O communications networks in their right-of-way and leasing the service to others. Still other utilities have leased just the right-of-way to a telecommunications provider for income or F/O access for their own use. Using a piece of the F/O highway for SCADA or automation is an opportunity. But if the highway needs to be extended to reach the substation, the cost can get high.

Typical F/O systems are based around high-capacity synchronous optical network (SONET) communications technology. Telecommunications people see these pathways as high-utilization assets and tend to try to add as many services to the network as possible. SCADA and automation communications can certainly be part of such a network. However, some industry experts believe that the power system operations communications, SCADA, ought to reside on its own network for security and not share the close proximity to corporate traffic that is part of an F/O network.

F/O technology has another application that is very valuable for SCADA and automation. Because F/O is nonconductive, it is a perfect medium for connecting communicating devices that may not share a solid ground plane. This is typical of substation equipment. These applications do not need the high bandwidth properties and use simple low-speed F/O modems. F/O cable is also low cost. This allows devices in outbuildings to be safely interconnected. It is also an excellent method to isolate radio equipment from substation devices to lessen the opportunity for lightning collected by radios to damage substation devices.

6.7 Testing Automation Systems

Testing assures the quality and readiness of substation equipment. A substation automation system will require testing at several points along its life span. It is important to make allowances for testing within the standard practices of the utility. While testing practices are part of the utility “culture,” designing the

testing facilities for substation automation system with enough flexibility to allow for culture change in the future will be beneficial. Surely, testing can have a great impact on the availability of the automation system and, under some circumstances, the availability of substation power equipment and substation reliability. Testing can be a big contributor to the cost of operation and maintenance.

6.7.1 Test Facilities

Substation automation systems integrate IEDs whose primary function may be protection, operator interface, equipment control, and even power-interchange measurement for monetary exchange. A good test plan allows for the automation functions to be isolated from the substation while the primary functions of the IEDs remain in operation.

6.7.1.1 Control

It is necessary to test automation control to confirm control-point mapping to operator interfaces and databases. This is also necessary for programmed control algorithms. Utilities want to be sure that the right equipment operates when called upon. Having the wrong equipment operate, or nothing at all operate, will severely hamper confidence in the system. Since any number of substation IEDs may be configured to control equipment for the system, test methods must be devised to facilitate testing without detrimental impact on the operation of the substation. Disconnect points and operation indicators may be needed for this purpose. For example, if a breaker-failure relay is also the control interface for local and remote control of a circuit breaker, then it should be possible to test control functions without having to shut the breaker down, which would leave the circuit without breaker-failure protection. If the breaker-control portion of the breaker-failure relay can be disabled without disabling its protective function, then testing can be straightforward. However, some utilities solve this problem by disabling all the breaker-failure outputs and allowing the circuit breaker to remain in service without protection for short periods of time while control is being tested. Other utilities rely on a redundant device to provide protection while one device is disabled for testing. These choices are made based on the utility's experience and comfort level. Work rules sometimes dictate testing practices.

While being able to disable control output is necessary, it is also important to be able to verify the control output has occurred when it is stimulated. With IEDs, it is often not possible to view the control output device, since it is buried within the IED. It may be useful to install indicators to show when the output device is active. Otherwise, at least a temporary indicating device is needed to verify that control has taken place. At least once during commissioning, every control interface should operate its connected power equipment to ensure that the interface actually works.

6.7.1.2 Status Points

Status-point mapping must also be tested. Status points appear on operator interface displays and logs of various forms. They are important for knowing the state of substation equipment. Any number of IEDs can supply status information to an automation system. Initially, it is recommended that the source equipment for status points be exercised to evaluate the potential for contact bounce to cause false indications. Simulating contact state changes at the IED input by shorting or opening the input circuits is often used for succeeding tests. Disconnect points make that task easier and safer.

As with control points, some care must be exercised when simulating status points. Status changes will be shown on operator interfaces and entered into logs. Operators will have to know to disregard them and cleanse the logs after testing is completed. Since the IED monitors the status point for its own function, the IED may need to be disabled during status-point testing. If the automation system has programmed logic processes running, it is possible that status changes will propagate into the algorithms and cause unwanted actions to take place. These processes need to be disabled or protected from the test data.

6.7.1.3 Measurements

Measurements may also come from many different substation IEDs. They feed operator interfaces, databases, and logs. They may also feed programmed logic processes. Initially, IEDs that take measurements need to

have their measurements checked for reasonability. Reasonability tests include making sure that the sign of the measurement is as expected in relation to the power system and that the data values accurately represent the measurements. Utilities rarely calibrate measuring IEDs as they once did transducers, but reasonability testing should uncover scaling errors and incorrectly set CT and PT ratios. Most utilities provide disconnect and shorting switches (test switches) so that measuring IEDs can have test sources connected to them. That allows known voltages and currents to be applied and the results checked against the expected value. Test switches can be useful in the future if the accuracy of the IEDs falls into question. Switches also simplify replacing the IED without shutting down equipment if it fails in service.

Some IEDs allow the user to substitute test values in place of “live” measurements. Setting test values can greatly simplify checking the mapping of values through the system. By choosing a signature value, it is easy to discern test from live values as they appear on screens and logs. This feature is also useful for checking alarm limits and for testing programmed logic.

During testing of IED measurements, some care must be exercised to prevent test data from causing operator concerns. Test data will appear on operator interface displays and may trigger alarm messages and make log entries. These must be cleansed from logs after testing is completed. Since measuring IEDs may feed data to programmed logic processes, it is important to disable such processes during testing to prevent unwanted actions. Any substituted values need to be returned to live measurements at the end of testing as well.

6.7.1.4 Programmed Logic

Many substation automation systems include programmed logic as a component of the system. Programmed logic obtains data from substation IEDs and provides some output to the substation. Output often includes control of equipment such as voltage regulation, reactive control, or even switching. Programmed logic is also used to provide interlocks to prevent potentially harmful actions from taking place. These algorithms must be tested to insure they function as planned. This task can be formidable. It requires that data inputs are provided and the outputs checked against expected results. A simulation mode in the logic host can be helpful in this task. Some utilities use the simulator to monitor this input data as the source IEDs are tested. This verifies the point mapping and scaling. They may also use the simulator to monitor the result of the process based on the inputs. Simulators are valuable tools for testing programmed logic. Many programs are so complex that they cannot be fully tested with simulated data; therefore their results may not be verifiable. Some utilities allow their programmed logic to run off of live data with a monitor watching the results for a test period following commissioning to be sure the program is acceptable.

6.7.2 Commissioning Test Plan

Commissioning a substation automation system requires a carefully thought-out test plan. There needs to be collaboration between users, integrators, suppliers, developers, and constructors. Many times, the commissioning test plan is an extension of the factory acceptance test (FAT), assuming a FAT was performed. Normally the FAT does not have enough of the substation pieces to be comprehensive, therefore the real “proof test” will be at commissioning. Once the test plan is in place, it should be rigorously adhered to. Changes to the commissioning test plan should be documented and accepted by all parties. Just as in the FAT test, a record of deviations from expected results should be documented and later remediated.

A key to a commissioning test plan is to make sure every input and output that is mapped in the system is tested and verified. Many times this can not be repeated once the system is in service.

6.7.3 In-Service Testing

Once an automation system is in service it will become more difficult to test it thoroughly. Individual IEDs could be replaced or updated without a complete end-to-end check because of access restriction to portions of the system. Utilities often feel that exchanging “like for like” is not particularly risky.

However, this assumes the new device has been thoroughly tested to insure it matches the device being replaced. Often the same configuration file for the old device is used to program the new device, hence further reducing the risk. Some utilities purchase an automation simulator to further test new additions and replacements.

However, new versions of IEDs, databases, and communications software should make the utility wary of potential problems. It is not unusual for new software to include bugs that had previously been corrected as well as new problems in what were previously stable features. Utilities must decide the appropriate level of testing for new software versions. A thorough simulator and bench test is in order before deploying new software in the field. It is important to know what versions of software are resident in each IED and the system host. Keeping track of the version changes and resulting problems can lead to significant insights.

Utilities must also expect to deal with in-service support issues that are common to integrated systems.

6.8 Summary

The addition of SA systems control impacts station security and deserves a great deal of consideration. It should be recognized that SA control can concentrate station controls in a small area and can increase the vulnerability of station control to human error and accident. This deserves careful attention to the control interface design for SA systems. The security of the equipment installed must ensure freedom from false operation, and the design of operating and testing procedures must recognize and minimize these risks.